BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

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| IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCE (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COAT RATES. | ) | CASE NO. GNR-E-11-03 |

# DIRECT TESTIMONY OF RICK STERLING

IDAHO PUBLIC UTILITIES COMMISSION

MAY 4, 2012

Q. Please state your name and business address for the record.

A. My name is Rick Sterling. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as the Engineering Supervisor.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Civil Engineering from the University of Idaho in 1981 and a Master of Science degree in Civil Engineering from the University of Idaho in 1983. I worked for the Energy Division of the Idaho Department of Water Resources from 1983 to 1994. My work focused primarily on development of renewable energy resources, and also on agricultural energy conservation. In 1988, I received my Idaho license as a registered professional Civil Engineer. I began working at the Idaho Public Utilities Commission in 1994. My duties at the Commission include analysis of a wide variety of electric, water, and gas utility applications. I have been the lead Staff person on all PURPA-related matters that have come before the Commission since 1994. I am also responsible for supervising the work of three engineers and four utility

analysts.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to discuss the proposals of Idaho Power, PacifiCorp, and Avista made pursuant to Order Nos. 32352 and 32388. These proposals relate to the determination of avoided cost rates for Qualifying Facilities (QFs) under the Public Regulatory Policies Act of 1978 (PURPA). More specifically, I will discuss my position on changes to both the Surrogate Avoided Resource (SAR) methodology and the Integrated Resource Plan (IRP) methodology as proposed by each of the utilities. I will also address other issues raised in this proceeding, including maximum contract length, QF contracting procedures and rules, curtailment rules, and ownership of Renewable Energy Credits (RECs).

**Summary of Recommendations**

Q. Please summarize your recommendations.

A. My testimony discusses and recommends the following:

1. That the Commission retain the use of the SAR methodology for computing avoided cost rates for wind and solar QFs 100 kW and smaller (nameplate capacity) and for all other resource types 10 aMW and smaller;

2. That the Commission order the fuel price

forecast published annually by the U.S. Department of Energy, Energy Information Administration in its Annual Energy Outlook to be used to update published avoided cost rates on July 1 of each year;

3. That the Commission adopt other changes to the SAR methodology as discussed by Staff witness Dr. Cathleen McHugh;

4. That the utilities implement both the SAR methodology and the IRP methodology in such a way as to not include any value for QF capacity provided in years when the utility is in a surplus position;

5. That avoided cost rates computed under both the SAR and IRP methodologies be reduced during surplus years to account for costs associated with transmission wheeling and losses;

6. That a simple cycle combustion turbine (SCCT) be used as the basis for computing capacity value under the IRP methodology for all resource types;

7. That the utilities be permitted to update fuel price forecasts, load forecasts, and long-term contract commitments (including QF contracts) between biennial IRP filings for the purposes of computing avoided costs under the IRP methodology,

8. That maximum contract length be reduced to five years for contracts containing rates computed under

the IRP methodology;

9. That all three utilities be directed to submit tariffs similar to PacifiCorp's proposed Schedule 38 outlining QF contracting procedures and rules;

10. That the rates contained in PURPA contracts not be locked-in more than five years prior to the scheduled operation date of the QF;

11. That the proposed curtailment tariff (Schedule 74) proposed by Idaho Power be approved; and

12. That the Commission order that ownership of Renewable Energy Credits (RECs) be assigned to the utility.

Q. First, as a preliminary matter, do you believe that there are changes that need to be made in the way in which PURPA is being implemented in Idaho?

A. Yes, of course. I think that the utilities have done a good job in their testimony in this proceeding as well as in testimony in earlier phases of this proceeding pointing out some of the problems with the way PURPA is being implemented and the serious consequences that have resulted. I am convinced that the problems they discuss are real and that the consequences are serious. In my opinion, the single biggest problem with the current avoided cost methodology is that it fails to account for whether a utility actually needs new

generation.

Q. Do you believe that the problems that have been previously identified exist for all three utilities?

A. Yes, although clearly the consequences are most severe for Idaho Power because it has experienced so much more PURPA development in its service territory than the other utilities. Nonetheless, despite the impact being most severe for Idaho Power, I believe that some of the problems that have been identified exist for all of the utilities. Consequently, I propose that if the Commission decides to make changes to avoided cost computation methodologies or to other policies related to QFs, that those changes and policies apply to all three utilities unless there are clear reasons for utility-specific policies.

**SAR Methodology**

Q. Idaho Power has proposed that the SAR methodology, which is currently used to compute "published" avoided cost rates, be abandoned in favor of using the IRP methodology for "standard" wind, solar, baseload, and canal drop hydro facilities. Do you agree with Idaho Power's proposal to abandon the SAR methodology for small projects?

A. No, I do not. While I agree with Idaho Power that the IRP methodology holds some advantages, even for

computing standard rates for small projects, I do not believe that the advantages are great enough to warrant abandonment of the SAR methodology entirely. The SAR methodology has been employed in Idaho for computing avoided cost rates since PURPA was first implemented. Although it has been necessary to occasionally modify the method and while it requires some vigilance to ensure input variables and price assumptions are kept updated, the method has generally proved satisfactory. Indeed, the vast majority of PURPA contracts approved to date contain rates computed using the methodology. Project developers have shown a clear preference for the method, admittedly mostly due to its ability to produce favorable rates, but also, I believe, because of its transparency. As long as application of the SAR method is restricted to only relatively small projects, I believe it can continue to be successfully used. Furthermore, if fuel prices and other assumptions used in the model are kept updated, then the avoided cost rates calculated using the methodology should be reasonably close to the rates calculated under the IRP methodology. The SAR methodology is intended to model the cost of a CCCT, while CCCTs are frequently the units setting the market clearing prices under the IRP methodology. The rates under each methodology will never match exactly, but they

should be reasonably close.

**100 kW Cap for Wind & Solar Under SAR Methodology**

Q. Existing rules require that eligibility for avoided cost rates computed using the SAR methodology be limited to facilities no larger than 100 kW (nameplate capacity) for wind and solar projects and 10 aMW for all other resource types. Do you believe that these eligibility limits should be retained?

A. Yes, I do. The 100 kW limit for wind and solar facilities was implemented on a temporary basis, beginning on December 14, 2010, in Case No. GNR-E-10-04 (*See* Order No. 32176) primarily to address the disaggregation issue related to wind and solar facilities. The ability of these resource types to disaggregate still exists as long as the financial incentive remains. The specific size limit of 100 kW was selected because FERC rules implementing PURPA require that standard rates be established for qualifying facilities with a design capacity of 100 kW or less. (*See* 18 CFR 292.304(c)). The 10 aMW limit has been in place for many years for other resource types, and I see no compelling reason to change it at this time, provided fuel prices are updated. Both Avista and PacifiCorp have also proposed that the SAR method and its current eligibility limits be retained.

Q. If the SAR method is retained for small QFs, are there modifications you think should be made to the methodology?

A. Yes, there are a few. First, Staff believes that the fuel price forecast used in the model should be updated annually using DOE EIA Annual Energy Outlook. In addition, we believe that the model should be modified to account for utilities' surplus periods. Staff witness Dr. Cathleen McHugh discusses Staff's proposed modifications to the SAR methodology in more detail in her testimony.

**IRP Methodology**

Q. Idaho Power proposes that the IRP methodology be used to compute avoided cost rates for QFs of all sizes, with "standard" wind, solar, baseload and canal drop facilities used as the basis for rates for small QFs. Do you agree with this proposal?

A. No, as I explained previously, I believe that the SAR method should continue to be used for solar and wind facilities up to 100 kW nameplate and for all other project types up to 10 aMW.

**Avoided Cost of Energy**

Q. Idaho Power, in the testimony of Karl Bokenkamp, proposes to use the AURORA model to determine the highest displaceable incremental cost being incurred

during each hour of the QF's proposed contract term. Do you agree with Idaho Power's approach?

A. Yes, I do.

Q. Idaho Power witness Bokenkamp, at page 13 of his direct testimony, explains how the Company proposes to treat long-term firm purchases. He explains that "if the firm purchase is resold at market price and the QF generation is accepted, then the incremental cost avoided is the net proceeds from the resale of the firm purchase after any transaction-related costs such as transmission costs, losses, etc." However, to simplify the analysis, Idaho Power proposes to disregard the transaction-related costs and losses. Do you think this is appropriate?

A. No, I do not. Although it would simplify the analysis, transaction-related costs and losses are real and could be significant in many cases; therefore, they should rightfully not be borne by Idaho Power and its ratepayers. In a production request, Staff asked Idaho Power to estimate these costs. Idaho Power responded by stating that transaction costs associated with reselling any of Idaho Power's longer-term firm purchases will depend on the location and timing of the purchases, and on actual market conditions. The Company identifies several alternatives to consider: (1) resell at the point of purchase, (2) deliver the purchase to Idaho Power's

system and then resell it at Idaho Power's border, (3) wheel the energy from Idaho Power's border to a more liquid market, or (4) wheel from the point of purchase to a more liquid market. (*See* Idaho Power Company's Response to Staff Request No. 18). In all except the first scenario, Idaho Power admits that it would incur transmission costs and losses. As a reasonable estimate, I would recommend that transmission costs be based on moving surplus energy from Idaho Power's system to the Mid-C market. Under this assumption, transmission costs would be $3 per MWh and losses would be approximately $1.50 per MWh.

Q. Under the method used by Idaho Power for computing the avoided cost of energy, an assumption is made that in order to be displaceable, a resource has to be online and capable of staying online and further reducing its output. Therefore, under Idaho Power's method, not all resources are entirely displaceable. Do you agree with the assumptions and methods proposed by Idaho Power?

A. Yes, I do. I believe that Idaho Power has properly focused on the <u>incremental costs</u> that the utility would incur as the basis for determining avoided costs. The focus on incremental cost appears entirely consistent with the definition of avoided cost as

contained in 18 C.F.R. 292.101(b)(6). Furthermore, I believe that the IRP methodology as proposed by Idaho Power conforms more closely with FERC's definition of avoided cost than the way in which Idaho Power has employed the methodology in the past.

Q. Has Staff reviewed in detail the manner in which Idaho Power proposes to calculate the avoided cost of energy? If so, did Staff's review identify any errors in Idaho Power's computations of energy value?

A. Yes, Staff thoroughly reviewed Idaho Power's methods for calculating the avoided cost of energy. In our review, we identified a couple of errors. First, in the energy component figures provided in the Company's direct testimony and exhibits, the Company used an outdated natural gas price forecast. The Company has used its updated forecast to recompute the energy values and has incorporated the results of that recomputation in results provided in Idaho Power's Supplemental Response to Staff Production Request No. 2. The effect of using a more updated gas forecast is a small decrease in the proposed avoided cost rates. Second, Staff discovered that the displaceable incremental costs for various thermal units were not being properly escalated in Idaho Power's analysis to compute the avoided cost of energy. Idaho Power corrected this error in the results provided

in Supplemental Response to Staff Production Request No. 2. The effect of this correction was a small increase in the avoided cost of energy. The combined effect of both corrections, one positive and the other negative was only a small change to the avoided cost rates.

In our review, Staff also identified instances in which it appeared that Idaho Power was operating one of its own resources during hours when prices in the market were lower. However, further analysis seems to indicate that Idaho Power was likely forced to operate its own higher cost resources in these hours because of either transmission constraints or because of minimum up times of its thermal resources. Consequently, Staff is satisfied that the analysis performed by Idaho Power is correct.

Q. Idaho Power's testimony describes its proposed methodology for computing the avoided cost of energy as being different than the currently approved methodology. Are the two methodologies actually different, and if so, are the differences acceptable?

A. Yes, the methodologies are different. However, I believe that the differences are reasonable. One of the primary reasons for the differences is because under the currently approved methodology, there has always been

1 a presumption that the dispatch of existing resources
2 would change, or alternatively, that a new resource would
3 be displaced or deferred. In most cases, however, new QF
4 resources are too small to affect dispatch or resource
5 decisions in AURORA. Therefore, unless some modification
6 is made to the currently-approved methodology, it is not
7 being implemented in the way in which it was intended.
8 Consequently, I believe that the methodology as proposed
9 by Idaho Power is acceptable, and as I stated previously,
10 an improvement over the currently-accepted methodology.
11 Q. One of the key underlying assumptions made by
12 Idaho Power in its modified methodology for computing the
13 avoided cost of energy is that QF generation is not used
14 to make market sales at AURORA-generated market clearing
15 prices. Do you agree with this assumption?
16 A. Yes, I do. I think this assumption is
17 fundamental in order to comply with PURPA as it was
18 intended. Utilities should not be required to make
19 purchases under PURPA in a particular hour if by doing so
20 it is concurrently required to make an equivalent and
21 offsetting sale in order to balance its system.
22 **Avoided Cost of Capacity**
23 Q. The utilities propose that the value of
24 capacity not be included in avoided cost rates during
25 periods when the utility is surplus. Do you agree with

1 this approach?

2 A. Yes, I do. I believe that the failure to
3 account for the utilities' need for new generation is one
4 of the most serious problems that needs to be addressed
5 in this case. It is well established that utilities must
6 honor their obligation under PURPA to purchase power
7 offered by QFs. However, utilities are not required, in
8 fact, they are not permitted, to pay more than their
9 avoided cost for capacity and energy provided by a QF.
10 The proper mechanism for accounting for utility need is
11 not to relieve utilities of their obligation to purchase,
12 but instead to establish prices for capacity and energy
13 that properly recognize the utilities' need, or lack of
14 need, for capacity and energy. By not paying for
15 capacity during surplus periods, utilities would be
16 paying what amounts to a more accurate reflection of a
17 true avoided cost.

18 Q. Is a utility's need for capacity and energy
19 taken into account under the IRP methodology?

20 A. Yes, I believe that it is under the IRP methods
21 proposed by the utilities in this case. Capacity and
22 energy deficit positions are recognized by the IRP models
23 used by the utilities, and appropriate resources are
24 added at appropriate times in order to satisfy those
25 deficits. If a utility does not have a need for a new

capacity or energy resource, then one is not added until it is needed. Energy values computed by the models are based on economic dispatch of all resources in the utility's portfolio at any given time, subject to the operating constraints and requirements of the various resources.

All three of the utilities use methods to determine capacity values under the IRP methodology outside of using their dispatch models (AURORA, GRID, and PRiSM). In the methods used by each utility, none assign capacity value to QFs in years when the utility is in a surplus condition.

Q. Didn't the SAR methodology, at one time attempt to account for a utility's surplus period in computing avoided cost rates?

A. Yes, it did, from the time PURPA was implemented in Idaho up until 2002, in Case No. GNR-E-02-01, Order No. 29124. At that time the Commission abandoned consideration of utilities' surplus periods in the computation of avoided cost rates for a variety of reasons as discussed in the direct testimony of Avista witness Clint Kalich. While all of the reasons for abandoning consideration of surplus periods made good sense at the time, and while some of the concerns may still be valid today, I believe that the need for

consideration of surplus periods now outweighs those concerns. Any difficulty that may exist in considering surplus periods can be overcome by careful definition of the term "surplus." I believe that Mr. Kalich has discussed an acceptable method for determining when a utility is energy or capacity surplus based on its summer and winter load-resource balance.

**SCCT vs. CCCT as the Basis for Determining Capacity Value**

Q. Idaho Power proposes that a simple cycle combustion turbine (SCCT) be used as the basis for computing the capacity cost component of avoided cost rates. Do you agree with this approach?

A. Yes, I do. I made a similar recommendation in Staff's comments in Case Nos. IPC-E-11-10 (Interconnect Solar), and IPC-E-11-26 (High Mesa Energy). Idaho Power, in both of these cases, calculated capacity value using a CCCT rather than an SCCT. Because of the relatively low expected capacity factor of these projects, the intermittent nature of their generation, and the fact that they cannot be expected to deliver capacity with complete certainty during the time of the utility's system peak, I felt that a SCCT would be more appropriate than a CCCT for computing capacity value.

Q. Do you agree with Idaho Power's proposal to use an SCCT for computing capacity value for all resource

1 types regardless of their operating characteristics?
2 A. Yes, I do. SCCTs are generally added to
3 utilities' resource portfolios to satisfy capacity-only
4 needs, and are usually the least cost capacity resource
5 available. Therefore, the cost of an SCCT can reasonably
6 be considered a capacity-only cost. Utilities that add
7 CCCTs to their portfolio do so because they have a need
8 for both capacity and energy, thus the cost of a CCCT can
9 be considered both a capacity and energy cost. CCCTs,
10 because they are more efficient, generate energy at a
11 lower variable cost than SCCTs, but the tradeoff is that
12 they are more costly to construct.
13 Under the methodology as proposed by the
14 utilities, capacity and energy values are being
15 calculated independently. Therefore, I maintain that the
16 proper resource to use as the basis for computing
17 capacity value is the lowest cost resource that could be
18 added to provide capacity equivalent to what would
19 otherwise be provided by the QF. I believe that using a
20 SCCT is probably most appropriate because it represents
21 the lowest cost, nearly capacity-only resource.
22 Q. PacifiCorp proposes that a deferrable CCCT,
23 rather than an SCCT, be used as the basis for computing
24 capacity cost. Do you agree with this approach?
25 A. Although the Company's rationale is sound

because CCCT capacity is, in fact, what might presently be deferred by the addition of a QF, I still believe that basing capacity value on the cost of an SCCT is more appropriate for the reasons stated previously.

**Peak Hours for Analyzing System Peak**

Q. In evaluating a potential QFs contribution to meeting the utility's system peak for purposes of computing capacity value, Idaho Power proposes to consider the hours between 3:00 pm and 7:00 pm for all days in July. PacifiCorp proposes to consider the top 100 summer peak hours for the years 2007-2010. Do you believe either proposal is acceptable?

A. I believe there is room for improvement. I am not particularly concerned that each utility define its peak hours in precisely the same way because each utility's peak may occur at different times of the year and because the shape of the peak may differ between utilities. However, I do believe that it is important to consider hours symmetrically around the peak. For example, Idaho Power's approach of considering specific hours in the entire month of July may be too arbitrary. It could be that hours in the third or fourth weeks of June experience higher peak loads than corresponding weeks in late July. Consequently, I would recommend that Idaho Power revise its approach to better identify the

top peak summer hours independent of whether they occur in June or July.

**Comparison of Results**

Q. Have you prepared a comparison of the avoided cost rates computed by each of the utilities under the IRP methodology?

A. Yes, I have. Exhibit No. 304 shows the costs of energy and capacity computed by each of the utilities using the IRP methodology for four sample project types. Each sample project type was chosen in order to illustrate the range of difference in rates for projects with very different generation characteristics. The base load project type would be typical of a project with a very consistent year-round and diurnal generation pattern, such as a geothermal or biogas facility. The canal drop project type would be typical of most projects located on irrigation systems, with steady seasonal generation, but no generation in the non-irrigation season. The fixed photovoltaic solar system would be typical of a facility located in southern Idaho oriented to maximize on-peak generation. The wind project is intended to closely represent the same type of facility that has commonly been installed in southern Idaho in recent years. In making their calculations, each utility made exactly the same assumptions of the annual

generation amounts and timing for each respective sample resource type. It should be pointed out that the results shown in Exhibit No. 304 are preliminary and reflect Staff's understanding of the utilities' results as of the time of filing of this testimony. The calculated rates could change during the course of this case due to corrections, revised fuel forecasts, and changes in long-term contract commitments.

Q. What observations can you make from the results shown in Exhibit No. 304?

A. One observation is that the avoided cost of energy is quite similar for each of the three utilities. It is also similar for each of the resource types.

A second observation is that the differences in rates, both between utilities and between resource types is mostly attributable to differences in the avoided cost of capacity. For example, the avoided cost of capacity is extremely low for the wind project, for all three utilities. This is because of the low probability that wind will be able to provide capacity during the time of any of the utilities' peak load hours.

A third observation is that neither a canal drop project nor a fixed pv solar project provides much, if any, valuable capacity for Avista. This is because Avista is a winter peaking utility, and a canal drop

1 facility would not be operating in the winter and a solar
2 facility would provide only minimal capacity during
3 winter evening hours when Avista's peak occurs.
4 A fourth observation is that the rates for
5 canal drop hydro, at least for Idaho Power and
6 PacifiCorp, are higher than the rates for the other
7 resource types. This again is primarily due to the
8 capacity component of the rate being relatively high.
9 The capacity component is high for canal drop hydro for
10 two reasons. First, the capacity is provided during peak
11 summer hours when it is most valuable to the utility.
12 Second, the capacity value is spread over fewer kWhs than
13 for other resource types because a canal drop hydro
14 project would only be operating during the irrigation
15 season.
16 Q. Are the differences in the results for each
17 utility surprising to you?
18 A. No, I expected that the results would be
19 different for each utility because each utility's
20 circumstances are different.
21 Q. Are the differences in the results for each
22 resource type surprising to you?
23 A. No. Each resource type is quite different in
24 its generating characteristics; consequently, it is
25 reasonable to expect that each would provide different

value, particularly capacity value. Wind resources, for example, have a very low probability of providing capacity during the utilities' peak load hours, while base load types of resources have a high probability. Therefore, the capacity component of the avoided cost rate should reflect these differences in value.

**IRP Assumption Updates**

Q. The IRP methodology relies on numerous assumptions from the IRP such as fuel price forecasts, load forecasts, resource costs, load-resource balances, and composition of preferred portfolios. Do you believe that the assumptions contained in each utility's last acknowledged IRP should be locked-in for purposes of calculating avoided cost rates, or should updates to some of these assumptions be permitted in the interim between IRPs?

A. I believe that it is appropriate for some assumptions to be updated and for others to remain fixed. In my opinion, the items that should be allowed to be updated are fuel price forecasts, load forecasts, and new contract obligations (including new QF contracts).

Fuel price forecasts should be updated annually. I suggest that the timing of the updates coincide with whatever schedule is adopted for fuel price updates made under the SAR methodology. Unlike the

1 recommendation for use of the DOE/EIA Annual Energy
2 Outlook forecast for the SAR methodology, however, I
3 believe that utilities should be permitted to use the
4 same forecasts and sources (or combinations of sources)
5 as they use in their IRPs for use with the IRP
6 methodology. Although the utilities generally update
7 their fuel price forecasts more frequently than annually,
8 I believe that a more frequent update would complicate
9 contract negotiations if fuel prices are changed too
10 frequently.
11 Load forecasts should be updated no more
12 frequently than annually. New contract commitments
13 should be updated whenever a new commitment is made,
14 either for a long-term purchase or a sale. By long-term,
15 I am referring to any commitment made at least a year in
16 advance or one extending for a year or more in duration.
17 Short-term commitments, because they are usually made on
18 short notice and can frequently change, should not be
19 considered in the utility's load-resource balance used
20 for computing avoided cost rates.
21 New PURPA contracts should be included in the
22 load resource balance. However, I believe that they
23 should only be incorporated once a contract has been
24 signed by the QF and submitted to the utility for
25 signature. The mere indication of interest or request

1 for a contract is too speculative to justify
2 incorporating a change in the utility's load-resource
3 balance. PURPA contracts that are terminated, expire, or
4 that have approved modifications of their online dates
5 should also be immediately considered in the load
6 resource balance.
7 Q. Idaho Power proposes that a "queuing" process
8 be established such that upon its receipt of a written
9 request from a QF for contract pricing, the QF is
10 designated as "queued" and therefore considered in
11 calculating avoided cost rates. Do you agree with this
12 proposal?
13 A. No, not entirely. As I explained above, I
14 believe that new QFs should not be considered in avoided
15 cost rate calculations until a contract has actually been
16 signed. Technically, Idaho Power's avoided costs do not
17 change until a new QF has actually been added to the
18 resource portfolio. A QF that has not signed a contract
19 cannot yet be considered part of the resource portfolio.
20 However, once a contract is signed for one QF, the
21 avoided cost rate for all successive QFs, even if they
22 are still in negotiation of a contract, should also
23 change accordingly.
24 Q. What assumptions and variables do you recommend
25 remain fixed between IRP filings?

A. I recommend that all variables and assumptions other than the ones I just mentioned remain fixed. This would include, for example, the timing and composition of the portfolio of new resources to be added, new resource costs, resource characteristics, operational characteristics, transmission assumptions, discount rates and other financial assumptions.

**Contract Length**

Q. Idaho Power is proposing that maximum contract length be reduced from 20 years to 5 years. Do you agree with the Company's proposal?

A. Yes, I do.

Q. Has the Commission ever before limited contracts to five years or less?

A. Yes, it has. The Commission's policy with respect to standard contract length has evolved over the years. From 1980 when PURPA was first implemented in Idaho, through 1987, utilities were obligated to offer QFs up to 35-year contracts. The reason for the 35-year maximum contract length was that 35 years was the amortization period allowed for similar utility-owned facilities. A contract length that matched the project's amortization schedule served to make financing easier, and in effect, helped encourage QF development.

In 1987 (*See* Case No. U-1500-170, Order No.

21630) the Commission shortened the standard contract length to 20 years reasoning that risk and uncertainty inherent in long-range forecasting increases dramatically with time and that a shorter contract term would reduce that risk. The Commission ruled that contracts longer than 20 years would be available to QFs only upon a persuasive showing of need.

Nine years later, in 1996, the Commission again reexamined the issue of contract length. In Order No. 26576 in Case No. IPC-E-95-9, the Commission further shortened the required contract length from 20 years to five years for projects 1 MW and larger. In 1997, the Commission extended the five-year contract length limitation established for large QFs to smaller than 1 MW QFs as well. (*See* Case No. IPC-E-97-9, Order No. 27111). Shortly after approving Idaho Power's Application to limit all QF contracts to five years, both Avista and PacifiCorp petitioned for and received approval to limit all QF contracts to five years. (*See* Case Nos. WWP-E-97-8, Order No. 27212; UPL-E-97-4, Order No. 27213).

In 2002, the Commission increased maximum contract length from 5 years back to 20 years. The Commission explained that when it earlier had reduced maximum contract length to five years, there was an

expectation of widespread deregulation, more competitive markets, and greater reliance on short-term market purchases. However, by 2002, the Commission recognized that each of Idaho's regulated electric utilities were constructing or had recently constructed long-term new generation resources. In restoring 20 years as the maximum contract length, the Commission reasoned that a longer contract better coincides with the amortization period or planned resource life of the renewable or cogeneration resources being offered, better reflects the amortization period of generation projects constructed by the utilities themselves and will coincidently provide a revenue stream that will facilitate the financing of QF projects. (*See* Order No. 29029).

Q. During the approximately five and a half year period when contract length was limited to five years (September 1996 through May 2002), how many PURPA contracts were signed?

A. There was only one PURPA contract signed in Idaho during this time frame. However, at the time, the eligibility cap for published rates was also limited to facilities one megawatt or smaller. In addition, published rates were also quite low, primarily due to low natural gas prices. Furthermore, most PURPA hydro and cogeneration projects had already been developed, while

wind, solar and biogas technologies had yet to fully develop. The combination of all of these factors, not shortened contract length alone, caused very few PURPA projects to be developed in Idaho during this time period.

Q. But won't a five-year limit on maximum contract length, if approved, severely limit the ability of projects to obtain financing, thus making extensive project development unlikely?

A. I agree that development would likely slow considerably, at least under PURPA. However, large facilities could still be developed with long-term contracts in response to utility requests for proposal, just as they are in most of the rest of the country. Alternatively, projects could also sign PURPA contracts and renew them every five years as long as PURPA remains in effect. If the significantly lower rates proposed by various parties in this proceeding are ultimately adopted by the Commission, any project signing a contract at low rates would probably not want to be locked into those rates for 20 years, and would welcome the opportunity to sign new contracts at five-year intervals.

Q. Do you believe that the Commission has a responsibility to ensure contract lengths are long enough to enable QFs to obtain financing?

A. No, not necessarily. Long-term contracts have been used by the Commission in the past to boost development of PURPA projects. However, circumstances have changed. It would be contrary to the public interest to encourage PURPA development at a time when it is not needed to serve customers and at a time when poor economic conditions strain customers' ability to pay. I believe it would be good public policy for the Commission to use effective tools, such as limiting maximum contract length, to control the pace of PURPA development.

Q. Are there any requirements under PURPA regarding contract length?

A. No, FERC's regulations implementing PURPA are silent on contract length.

Q. Are there other reasons why you believe that maximum contract length should be shortened to five years?

A. Yes, there are. When the SAR was changed from a coal-fired resource to a gas-fired resource in 1995, fuel became a much larger portion of the avoided cost rate. By comparison, fuel is a far more substantial portion of costs for a gas-fired resource than for a coal-fired resource. In fact, for the gas-fired CCCT now used as the SAR, fuel represents approximately two thirds of the project costs. Currently, the fuel component of

costs must be estimated based on 20-year forecasts. As history has demonstrated, it can be extremely difficult to accurately forecast gas prices just a few years into the future, let alone 20 years into the future. Similarly, under the IRP methodology, much of the cost upon which PURPA rates are based is driven by fuel prices. Gas-fired generation is on the margin much of the hours of the year; consequently, electric market prices are frequently closely tied to natural gas prices. A five-year contract allows contract rates to be adjusted regularly to more accurately reflect current fuel prices.

The shorter the term of the contract, the more frequently prices can be adjusted to ensure they accurately represent the true value of the power. A shorter term contract helps to minimize risk for both the buyer and the seller.

Q. Some people have argued over the years that PURPA projects, because the prices are established at the start of the contract term and are fixed for the 20 years of the contract, present little or no fuel price risk compared to gas-fired generation acquired by utilities. Do you agree?

A. No, I do not. Although there may be no price uncertainty associated with long-term PURPA contracts, that is not the same as having no price risk. Prices

1 established at the start of a long-term contract could
2 prove to be too high or too low compared to other
3 alternatives or to market prices in effect throughout the
4 term of the contract. A long-term contract locks in
5 those prices, regardless of what happens with market
6 prices. Because 100 percent of PURPA costs are passed on
7 to customers through PCAs, ratepayers are fully exposed
8 to the risk that PURPA rates may prove to be too high.
9 Fuel costs associated with utility-owned
10 resources are also passed on to customers, partly through
11 base rates and partly through PCAs. However, fuel costs
12 are tracked annually and rates are adjusted accordingly.
13 Consequently, while customers are exposed to fuel price
14 risk for both PURPA and utility-owned resources, the
15 annual adjustment of rates for utility-owned resources
16 exposes customers to less risk for utility-owned
17 resources than for PURPA resources. Moreover, recovery
18 of costs for utility-owned resources is not guaranteed.
19 However, as previously stated, once a PURPA contract is
20 approved by the Commission, customers are obligated to
21 pay 100 percent of the costs.
22 Q. Is it your position that contracts be limited
23 to five years for all QFs, or only those eligible for
24 rates determined under the IRP methodology?
25 A. It is my position that contracts be limited to

1 five years only for those QFs eligible for rates
2 determined under the IRP methodology. Twenty-year
3 contracts should continue to be available to QFs under
4 the SAR methodology.
5 **QF Contracting Procedure & Rules**
6 Q. PacifiCorp proposes in this case that a tariff
7 (Schedule 38) be adopted specifying contracting
8 procedures and rules for QF contracts. Do you support
9 this proposal?
10 A. Yes, I do. The Commission has never maintained
11 rules or required specific procedures in the past, but I
12 believe that they could be helpful now for both the
13 utilities and project developers. A fair, consistent set
14 of rules and procedures would inform both parties of
15 their responsibilities, informational requirements, and
16 timelines. It could also help to alleviate complaints.
17 Q. Would you recommend that the tariff proposed by
18 PacifiCorp be adopted by the Commission for use by all
19 three utilities?
20 A. No. I believe that each utility needs to
21 develop its own tariff tailored to meet its own needs,
22 subject to approval of the Commission. I would recommend
23 that each of the utilities be directed to prepare similar
24 tariffs to PacifiCorp's Schedule 38, and that a separate
25 docket be opened for review and comment on the specific

1 details that would be contained in each proposed tariff.
2 Although Idaho Power has stated that it supports a
3 similar tariff, it has not submitted a draft proposed
4 tariff.
5 **Advance Contract Commitment, Price Lock-in**
6 Q. Avista proposes that utilities should not be
7 required to execute PURPA contracts more than five years
8 ahead of expected deliveries. Do you agree with this
9 proposal?
10 A. Although I agree with the objective of the
11 proposal, I think it may be difficult to implement in
12 order to ensure that it does not conflict with the
13 utility's obligation to offer to purchase under PURPA.
14 Avista has made a second proposal, however,
15 that could successfully achieve a similar objective.
16 Avista's second proposal is that rates contained in a
17 PURPA contract not be locked in more than two years ahead
18 of commercial operation. Project developers typically
19 need to obtain a power sales agreement and the certain
20 avoided rates contained within it before they can obtain
21 financing to proceed with their project. Completing the
22 project can then take several years, depending on the
23 type and size of the facility. A developer might
24 experience delays for various reasons while he diligently
25 pursues his project. But delays can also occur due to

1 deliberate actions or inactions of the developer. Many
2 things can change during the time a developer is working
3 on his project, including power prices. Although I
4 believe that a developer needs price certainty and the
5 assurance of a utility obligation to purchase during the
6 reasonable course of developing a project, I do not
7 believe that the same price certainty and assurance
8 should be preserved indefinitely. Few projects achieve
9 commercial operation within two years of contract
10 execution, but most achieve it within five years. I
11 believe five years after contract approval is a
12 reasonable period of time to preserve rates contained in
13 an initial contract. If a project cannot be completed
14 and achieve commercial operation within five years, then
15 the utility, while it may still have a continuing
16 obligation to purchase under PURPA, should be permitted
17 to recompute rates in the contract based on whatever
18 rules, assumptions and methods are in place at the time
19 of the recomputation. Avoided cost rates could either
20 increase or decrease in the interim between contract
21 execution and commercial operation; consequently, I
22 believe it would be fair to permit the utility to
23 recompute new rates after five years if they would be
24 lower than the original rates, or to maintain the
25 original rates if the QF's failure to achieve commercial

1 operation as scheduled is not the fault of the utility.
2 Q. Avista proposes that utilities be permitted to
3 terminate contracts 180 days beyond the committed online
4 date in the contract if projects fail to come online, and
5 that a security deposit for liquidated damages be due at
6 the time a legally enforceable obligation is incurred –
7 *i.e.*, Avista states, when the utility has tendered a
8 contract and the QF developer executes and returns the
9 tendered contract obligating the utility to purchase
10 contract output. Do you agree with these proposals?
11 A. I think utilities can already insert conditions
12 in contracts that allow them to terminate contracts 180
13 days beyond the committed online date when projects fail
14 to come online; therefore, I do not believe that any
15 further authorization from the Commission is necessary.
16 Security deposits for delay liquidated damages
17 have become standard in all recent PURPA contracts. A
18 requirement that a security deposit for liquidated
19 damages be due when a QF developer executes and returns
20 the tendered contract would be a change from current
21 practice. The Commission has never specified in any of
22 its orders the timing of when a security deposit is due.
23 However, I believe Avista's proposal has merit. It seems
24 fair that if a QF can unilaterally impose a legally
25 enforceable obligation on a utility, the QF should

contemporaneously incur a corresponding obligation to perform backed by a posting of required security for liquidated damages.

**Curtailment (Idaho Power Schedule 74)**

Q. Idaho Power proposes that the Commission approve a tariff (Schedule 74) that governs operational dispatch of QFs, including curtailment under certain circumstances. Do you support the proposed tariff?

A. Yes, I do. The proposed tariff would establish rules under which Idaho Power could curtail certain QFs if, due to operational circumstances, purchases from the QF would otherwise require the Company to dispatch higher cost, less efficient resources to serve system load or to make base load resources unavailable for serving the next anticipated load.

Q. Doesn't Idaho Power already have authority to curtail QFs under certain circumstances?

A. Yes, they do under Schedule 72 and under the terms of all PURPA power sales agreements, but only in response to system integrity issues. Schedule 72 generally addresses interconnection of non-utility generation, but specifically includes provisions that allow disconnection under circumstances in which "...the Seller's operation or maintenance of the Generation Facility or Interconnection Facilities is

unsafe or may otherwise adversely affect the Company's equipment, personnel, or service to its customers." Unlike Schedule 72 that gives the Company authority to curtail, the proposed Schedule 74 addresses policies and procedures for operational dispatch of Idaho Power's own resources in addition to QF resources.

Q. If Idaho Power already has authority to curtail QFs under certain circumstances, why is an additional tariff necessary?

A. As I stated, the existing Schedule 72 gives the utility the authority to curtail under certain circumstances, but the proposed Schedule 74 details specific policies and procedures to be followed under curtailment. I am aware that Idaho Power has curtailed wind projects on its system several times this year following the same procedures outlined in the proposed tariff. If Idaho Power intends to follow these procedures, it would be desirable that they be contained in a Commission-approved tariff to help ensure clarity, consistency, and fairness.

Schedule 74 would also address Idaho Power's ability to curtail for reasons related to system efficiency and economics, reasons not allowed under Schedule 72.

Q. Idaho Power proposes that Schedule 74 apply to

all QF facilities, both existing and new, that have Generator Output Limiting Controls (GOLCs) installed. Do you believe that, if approved, the Company would have the authority to apply the proposed tariff to existing facilities whose contracts were in place prior to the new tariff being adopted?

A. Yes, I do. As explained by Idaho Power witness Tessia Park, FERC rules at 18 CFR 292.304(f) includes a provision that relieves utilities from an obligation to purchase during any period which, due to operational circumstances, purchases from QFs will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself. Because this is a part of FERC rules, I think Idaho Power has always had that authority whether or not it is expressly spelled out in a contract or a tariff.

Q. Has clarification of 18 CFR 292.304(f) ever been made by FERC?

A. Yes. In Order No. 69, FERC clarified that 18 CFR 292.304(f) was intended to deal with a certain condition which can occur during light loading periods—conditions that I believe are properly explained by Idaho Power witness Park.

**Renewable Energy Credits**

Q. PacifiCorp in this case took a position that ownership of Renewable Energy Credits (RECs) associated with QFs should be assigned to the utilities. Idaho Power pointed out that REC ownership is being debated in Case No. IPC-E-11-15 and that, at the time Idaho Power filed its testimony, the Idaho Legislature was considering legislation addressing REC ownership. Avista was silent on the issue. Do you believe that this issue should be addressed in this proceeding?

A. Yes, I do. Depending upon one's point of view, RECs are either directly or indirectly associated with the capacity and energy produced and sold to utilities by nearly all QFs. Despite the fact that Idaho has not adopted any standards requiring that utilities possess RECs (*i.e.*, renewable portfolio standards), they nevertheless are generated by QFs and have value to whichever entity is deemed to own them. In addition, the disposition of RECs between the utility and the QF owner is typically addressed in most new power sales agreements, except for those in which the parties are unable to agree on REC ownership in which case the agreements are silent regarding ownership. While some recent contracts have been silent, others have granted full REC ownership to the QF owner, others have split REC

ownership 50/50 between the QF owner and the utility from the beginning of the contract throughout its entire term, while still others have split REC ownership with the QF possessing them for the first half of the contract term and the utility possessing them for the last half. Although negotiation of REC ownership has proven to be possible in some instances, parties have reached an impasse in other cases. Nonetheless, in every case, REC ownership has been an extremely contentious issue. I believe that rules need to be established in order to ensure consistency and to avoid disputes.

Q. PacifiCorp witness Clements proposes that Environmental Attributes (RECs, green tags) generated by a QF go to the utility whenever the QF sells energy to the utility and receives compensation for that energy at approved avoided cost rates. What is your position on this issue?

A. I agree with Mr. Clements that REC ownership should be decided in favor of the utilities, but my reasoning is a bit different.

Q. Can you summarize some of the common arguments made concerning REC ownership?

A. Yes. Arguments justifying REC ownership have been made throughout the country from the time when RECs were first defined. The arguments generally fall into

one or more of several categories. First, some arguments focus on the responsibility and timing of creation of the RECs. Some argue that the QF developer should own the RECs because the developer made the investment and took the risk in building the renewable facility, that the RECs are created the instant the kWhs are generated, and that absent the facility, no RECs would exist. Others argue that RECs are not created until the kWhs are sold to the utility, and that RECs owe their very existence to the fact that the energy was purchased by the utility, thus the utility should own the RECs.

A second class of arguments, similar to Mr. Clements', focuses on a belief that REC ownership by the utility is a necessary condition of purchases made from QFs because of the presumption that renewable attributes are an implied requirement for QFs under PURPA, and that stripping these attributes destroys the very essence of the product PURPA obligates utilities to purchase. This argument suggests that the purchaser of the energy should be entitled to all of the attributes of that energy.

A third class of arguments focuses on costs. The basic argument is that the avoided cost rate should take into account REC ownership. If the purchase by the utility of a kWh includes a bundled REC, then the price paid by the utility should be higher than if only the kWh

alone is delivered.

Q. Why do you believe that REC ownership should be decided in favor of the utilities?

A. All of the arguments summarized above have merit and may be persuasive in justifying REC ownership be either the utility or the QF. In the end, however, I believe that the public interest is paramount in any decision on REC ownership in Idaho. In my opinion, the public interest is best served if REC ownership is granted to the utilities.

For example, if Idaho was in a position where additional incentive was needed in order to stimulate further development of renewables or achieve an RPS standard, then it might be reasonable to assign ownership of RECs to QF project owners so that they would have an additional revenue stream that could enhance project economics. However, as recent history demonstrates, Idaho is not in a situation where renewables development is stalled or needs to be accelerated.

If the real purpose of an RPS standard is to stimulate renewables development, then it seems that objective is achieved once a renewable project is built. If a utility did not receive the RECs from that project and instead was forced to purchase or obtain RECs elsewhere, then it seems that twice the incentive would

be created for developing renewables projects—once for QF developers who sell RECs to out-of-state entities and once for the utility who must purchase RECs to satisfy its own requirements. Although such a result may not be intended, if an RPS requirement did exist and had to be met, utilities could be in a position of having to acquire RECs just to meet the standard when it might otherwise have been able to meet the standard using RECs associated with QFs from which it must purchase power under PURPA.

Q. Has FERC provided any guidance regarding REC ownership?

A. Yes, some. FERC has made clear that REC ownership is a matter for states to decide. The key case addressing REC ownership is the following: *American Ref-Fuel Company,* 105 FERC ¶ 61,004 (2003).

In *American Ref-Fuel*, several QFs had petitioned FERC for an order declaring that avoided cost contracts entered into pursuant to PURPA, absent express provisions to the contrary, do not inherently convey to the purchasing utility any RECs. *Id. at 61,005*. In response, FERC addressed the relationship between PURPA contracts for the sale of QF capacity and energy and the ownership of RECs. FERC specifically declared the following:

> 23....RECs are relatively recent creations of the States. Seven States have adopted Renewable Portfolio Standards that use unbundled RECs. What is relevant here is that the RECs are created by the States. They exist outside the confines of PURPA. PURPA thus does not address the ownership of RECs. And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, likewise do not control the ownership of the RECs (absent an express provision in the contract). States, in creating RECs, have the power to determine who owns the REC in the initial instance, and how they may be sold or traded; it is not an issue controlled by PURPA.
>
> 24. We thus grant Petitioners' petition for a declaratory order, to the extent that they ask the Commission to declare that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility (absent an express provision in a contract to the contrary). While a state may decide that a sale of power at wholesale automatically transfers ownership of the state-created RECs, that requirement must find its authority in state law, not PURPA.

*American Ref-Fuel, 105 FERC at 61,007.*

Thus, FERC concluded that RECs are created by the State and controlled by state law, not PURPA, and that they may be decoupled from the renewable energy. More specifically, FERC ruled that states have the power to determine who owns RECs.

Q. FERC's order in *Am Ref-fuel* says that contracts for the sale of QF capacity and energy entered into pursuant to PURPA do not convey RECs to the purchasing utility. Wouldn't it therefore be reasonable to conclude

1 that RECs are owned by the QF, absent an express
2 provision in the contract to the contrary?
3 A. No, I contend that such an interpretation can
4 only be reached by taking language from FERC's order out
5 of context. The Petitioners in *Am Ref-fuel* specifically
6 asked for a declaration that "contracts for the sale of
7 QF capacity and energy entered into pursuant to PURPA do
8 not convey RECs to the purchasing utility." FERC's
9 answer granted the petition and addressed the precise
10 question it was asked to decide. It went no further,
11 except to say that REC ownership is a matter for states
12 to decide. FERC was not asked to rule on the converse
13 question that contracts for the sale of QF capacity and
14 energy entered into pursuant to PURPA do not convey RECs
15 to the QF. I believe a reasonable interpretation of
16 FERC's order is that contracts under PURPA, absent
17 express provisions, do not convey RECs to either party,
18 nor do they dictate REC ownership. Any interpretation
19 that implies that FERC stated that QFs own RECS seems to
20 me to be a case of starting with a conclusion and working
21 backwards, and requires reading far more into FERC's
22 decision than is actually there. Similarly, any
23 suggestion that FERC determined that RECs are owned by
24 the QFs would, in my opinion, be inconsistent with FERC's
25 determination that REC ownership is a matter for states

1 to decide.

2 Q. Aside from the need for the Commission, the
3 Legislature, or the courts to determine REC ownership,
4 are there pricing issues associated with RECs that need
5 to be considered in setting avoided cost rates?

6 A. Yes, there are. For example, under the IRP
7 methodology, a utility's 20-year portfolio of new
8 resources is modeled in computing avoided cost rates.
9 Each utility's 20-year resource portfolio contains some
10 renewable plants because they either represent the lowest
11 cost resources or because they help satisfy expected RPS
12 requirements or both. The utility would possess the RECs
13 associated with resources contained in its preferred
14 portfolio, and presumably any price premium associated
15 with those RECs would be included in the cost of the
16 projects. Consequently, the cost of RECs would already
17 be accounted for in computing avoided cost rates using
18 the IRP methodology. Therefore, a utility paying the
19 computed avoided cost to a QF under the IRP methodology
20 should be entitled to ownership of the RECs.

21 Under the SAR methodology, however, because the
22 SAR is a gas-fired resource that does not produce RECs
23 and the QF is presumably a renewable resource that does
24 produce RECs, some adjustment to the avoided cost rates
25 may be necessary. If the utility is deemed to own the

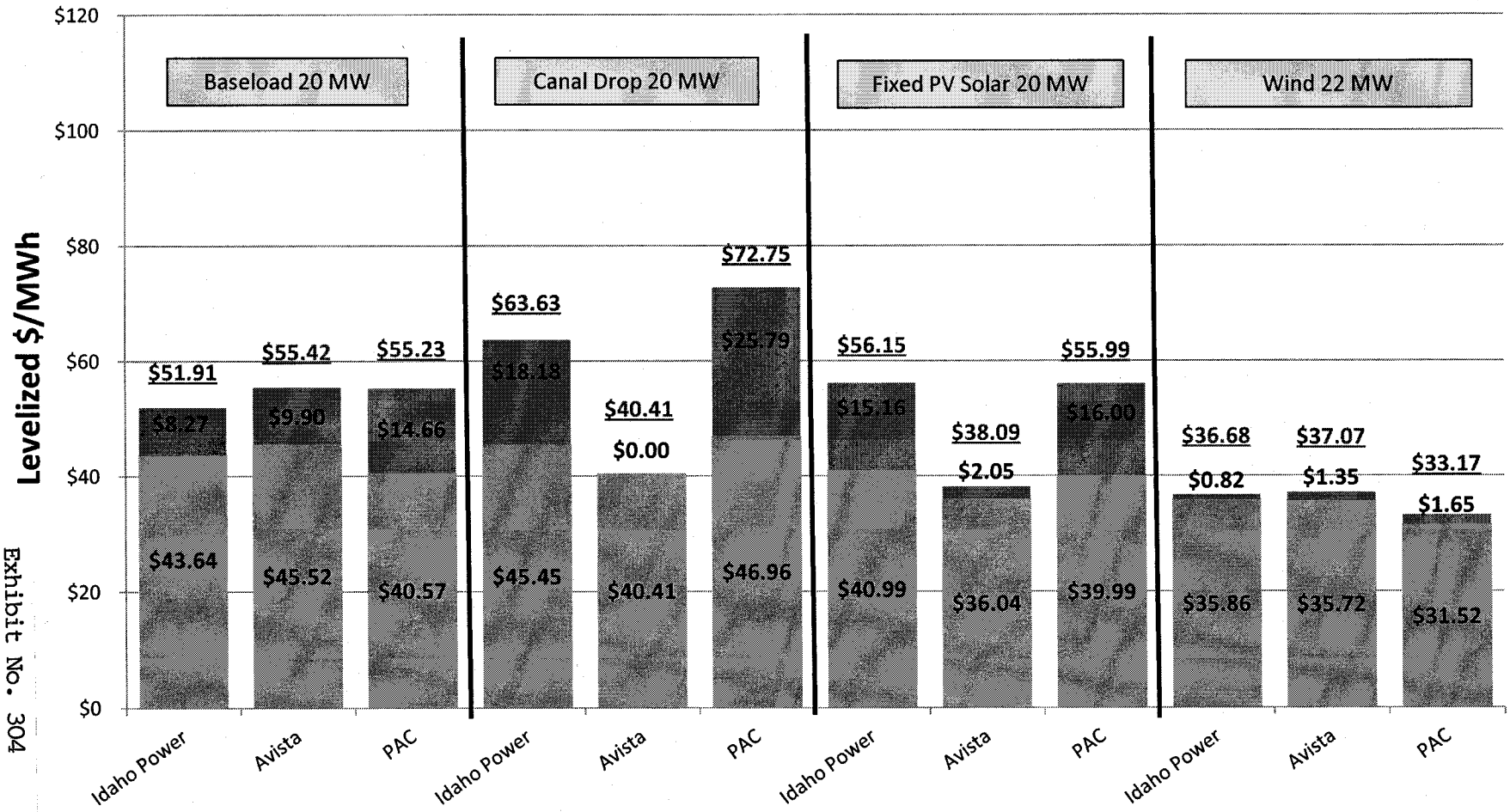
RECs associated with the QF, then an adjustment to the avoided cost rates is necessary because capacity and energy from the QF simply offsets capacity and energy otherwise provided by the SAR. The RECs would be a unique attribute of the power provided by the QF. The utility would then be expected to pay some amount in addition to the published avoided cost rates if it wished to own the RECs.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

# Comparison of Proposed IRP Methodology Rates

## Levelized Rates for 20-yr Contract Term, January 2013 Online Date




■ Avoided Cost of Capacity ■ Avoided Cost of Energy

All utilities have included an integration deduction in the Avoided Cost of Energy; Avista's rates also include deductions to account for transmission costs and losses.

Exhibit No. 304
Case No. GNR-E-11-3
R. Sterling, Staff
5/04/12

# CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 4TH DAY OF MAY 2012, SERVED THE FOREGOING **DIRECT TESTIMONY OF RICK STERLING,** IN CASE NO. GNR-E-11-03, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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